DIRECT TESTIMONY OF
JAMES W. NEELY, P.E.
ON BEHALF OF
DOMINION ENERGY SOUTH CAROLINA, INC.
DOCKET NO. 2023-9-E

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is James W. Neely and my business address is 400 Otarre Parkway, Cayce, South Carolina, 29033.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Dominion Energy Services, Inc. ("Dominion Energy") as an Energy Market Strategic Advisor in the Resource Planning department for Dominion Energy South Carolina, Inc. ("DESC" or the "Company").

Q. PLEASE DESCRIBE YOUR DUTIES RELATED TO RESOURCE PLANNING IN YOUR CURRENT POSITION.

A. I am responsible for modeling DESC's electric system for the purpose of preparing the Integrated Resource Plan ("IRP") and annual IRP Updates, assessing the results of Requests for Proposals ("RFPs") for generation resources, calculating avoided costs, forecasting fuel costs, and evaluating changes to electric generation.

Q. DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. In 1984, I graduated from Clemson University with a Bachelor of Science degree in electrical engineering. I received a Master of Science degree in management from Southern Wesleyan University in 2002. I received a Bachelor of Science degree from Mars Hill University in 1979. I was employed by South Carolina Electric and Gas Company ("SCE&G") as a design engineer at V.C. Summer Station from 1992 to 1997. In 1997, I went to work in the Resource Planning department for SCE&G as a Resource Planning Engineer. In 2013, I was promoted to Senior Resource Planning Engineer, and following the merger and integration activities with Dominion Energy, my title changed to Energy Market Consultant, then to Energy Market Strategic Advisor.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA ("COMMISSION")?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to discuss the structure and methodologies used to model resources for DESC's 2023 Integrated Resource Plan as well as discuss the analysis of the Build Plans.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized into four sections.

1. Resource Optimization Modeling
2. Market Scenarios
3. Build Plan Analysis
4. Modeling Inputs and Assumptions

RESOURCE OPTIMIZATION

Q. WHAT WAS THE METHODOLOGY USED TO DEVELOP THE BUILD PLANS MODELED IN THE IRP?

A. In Order No. 2020-832, the Commission ordered DESC to begin using capacity expansion software for selecting resource plans beginning with the 2022 IRP Update. As directed by the Commission in Order No. 2020-832, the Company established an ongoing IRP Stakeholder Process through which Stakeholders were engaged in developing the methodology, inputs, and assumptions used in this IRP and through which the PLEXOS model was selected as the resource optimization software. This resource optimization software was first implemented in the 2022 IRP Update.

Q. HOW DOES RESOURCE OPTIMIZATION DIFFER FROM PREVIOUS IRPs FILED BY DESC?

A. In prior IRPs, the Company constructed several resource portfolios to represent alternative approaches to meeting future resource needs and modeled the costs and other attributes of those resource portfolios across multiple future Market

Scenarios. Under resource optimization, the model itself selects resources to most efficiently meet a given Market Scenario or set of constraints.

Q. PLEASE DESCRIBE HOW RESOURCE OPTIMIZATION WAS USED TO CREATE THE BUILD PLANS IN THIS IRP.

A. DESC defined a set of eight (8) Market Scenarios in conjunction with Stakeholders for the PLEXOS model to optimize for creation of the Build Plans. The Market Scenarios vary by their assumptions regarding load growth, fuel prices, carbon prices, and DSM effectiveness. In a few scenarios, DESC set additional parameters or constraints to model Market Scenarios that are useful to evaluate the impact of specific market conditions such as achieving 70% and 85% carbon emissions reductions by the year 2050 (the "Carbon Constrained Build Plans") and comparing the impact of retiring the coal fired Williams Station ("Williams") in 2030 versus 2047. DESC also set certain conditions and assumptions for PLEXOS to use in creating each optimized Build Plan such as the costs of additional resources, retirement dates for Wateree and Williams, and the conversion of Cope Station to operating only on natural gas in 2031. The variable and fixed inputs are described in more detail later in my testimony.

The PLEXOS model was then run for each given set of conditions using a computationally intensive process to create an optimized Build Plan over the planning horizon. Because of the nature of the modeling, the more variables involved the more challenges the software faces in solving for the optimum solution and the fewer the variables, the more precise the optimization.

DESC created eight (8) of the fourteen (14) Build Plans by using PLEXOS to optimize resource additions under each of the eight (8) Market Scenarios. It created the additional six (6) Build Plans by imposing specific constraints, like carbon emissions constraints or retirement dates, on a Market Scenario. Each Build Plan is optimized to achieve lowest cost to customers under each Market Scenario or additional constraint.

Q. PLEASE DESCRIBE HOW PLEXOS WAS USED TO EVALUATE THE BUILD PLANS IN THIS IRP?

A. For the Core Analysis, DESC selected five of the optimized Build Plans that represent a range of wide but plausible future conditions. We then ran each of the Core Build Plans through PLEXOS's hourly dispatch model to determine their costs and CO_2 emissions under the three most likely or indicative Market Scenarios. This resulted in fifteen (15) Core Cases that provide a comparative basis to evaluate the Core Build Plans head-to-head under multiple market conditions.

MARKET SCENARIOS

Q. WHAT ARE THE EIGHT MARKET SCENARIOS?

A. The eight Market Scenarios reflect an internally consistent narrative about future environmental policy choices, fossil fuel costs and availability, levels of economic development and load growth, and DSM program results.

Collectively, the eight Market Scenarios encompass a broad spectrum of future conditions on DESC's electric system. These eight Market Scenarios are described in detail on page 54 of DESC's 2023 IRP, which is incorporated herein by reference.

Q. WHAT ARE THE THREE CORE MARKET SCENARIOS?

A. The Core Market Scenarios represent a range of assumptions for planning purposes that appropriately encompasses reasonable and indicative future conditions based on future regulatory policies, market conditions, and CO_2 emissions reduction goals. To allow for costs and emissions to be compared on an equal basis, all three Core Market Scenarios assume the same level of customer demand, specifically, all assume Reference Load Growth and a medium level of cost-effective DSM.

The three Core Market Scenarios are:

(1) The Reference Market Scenario. This Market Scenario generally reflects a middle-of-the-road outlook and reasonably foreseeable values for key market drivers in general. While there is currently no explicit price on CO_2 and the design of future policy is uncertain, this Market Scenario assumes that a moderate CO_2 price is imposed on the electric sector as a proxy for future policies that increase the cost of fossil-fired resources. It assumes that DSM programs attain the achievable potential load reductions as determined in the 2023 DSM Potential Study.

(2) **High Fossil Fuel Prices Market Scenario.** This Market Scenario represents a future in which high fossil fuel prices combine with moderate levels of electric demand growth. It assumes that state and federal policies constrain investments in coal and natural gas supplies and the expansion of natural gas pipelines resulting in high fossil fuel prices. Electrification of transportation and other end uses offset the effect of high prices and energy conservation on electric load growth. DSM programs attain the achievable potential load reductions as determined in the 2023 DSM Potential Study.

(3) **Zero Carbon Cost Market Scenario.** This Market Scenario represents a future in which decarbonizing the energy sector is not prioritized. It assumes a future energy market in which CO_2 emissions have a zero cost and DSM programs attain their achievable potential. Electrification does not dramatically increase load growth and fossil fuel prices remain in a moderate range.

BUILD PLAN ANALYSIS

Q. WHAT ARE THE FIVE CORE BUILD PLANS?

A. The five Core Build Plans are the three optimized Build Plans under the Core Market Scenarios, plus two additional Build Plans optimized under the Reference Market Scenario with additional constraints set to achieve certain carbon emissions reduction targets by 2050. These five Core Build Plans were selected for detailed analysis and define a broad range of possible options for future planning, or in the case of the Reference Build Plan, represent middle-of-the-road assumptions about the future of energy markets in South Carolina and the most likely and representative generation planning inputs. These five Core Build Plans are: (1) the Reference Build Plan; (2) the Zero Carbon Cost Build Plan; (3) the High Fossil Fuel Prices Build Plan; (4) the 70% CO_2 Reduction Build Plan; and (5) the 85% CO_2 Reduction Build Plan.

Q. WHAT METRICS WERE USED TO EVALUATE THE BUILD PLANS?

A. The IRP Statute and Commission directives specify that DESC should assess its Build Plans against resource adequacy and capacity to serve anticipated peak electrical load, and applicable planning reserve margins; consumer affordability and least cost; compliance with applicable state and federal environmental regulations; power supply reliability; commodity price risks; diversity of generation supply; and other foreseeable conditions that the Commission determines to be for the public interest. The 2023 IRP complies with these requirements by assessing its Build Plans against eight specific metrics: levelized cost, CO_2 emissions, clean energy, fuel cost resiliency, generation diversity, reliability factors, mini-max regret and cost range. In addition, each build plan is created to meet a minimum reserve margin. This analysis is contained on pages 63 to 71 in the 2023 IRP and is incorporated herein by reference.

Q. WHAT ARE THE KEY CONCLUSIONS DRAWN FROM THE CORE ANALYSIS?

A. The Core Analysis shows that across all fifteen Core Cases, the Reference Build Plan had the lowest, or the second lowest cost to customers expressed as the levelized net present value ("LNPV") cost per year for generation supply as shown in the following table. The results are color coded: 1. Green = Least Cost, 2. Light Green = Second, 3. Yellow = Third, 4. Orange = Fourth and 5. Red = Highest Cost.

Table 1. Levelized Cost Comparison of the Core Build Plans (30-Year LNPV in Millions of Dollars)

Core Build Plans 30 Yr LNPV ($M)			
Build Plans	**Reference Market Scenario**	**High Fossil Fuel Prices Market Scenario**	**Zero Carbon Cost Market Scenario**
Reference	1,884	2,177	1,809
High Fossil Fuel Prices	1,954	2,200	1,838
Zero Carbon Cost	1,895	2,187	1,774
70% CO_2 Reduction	2,072	2,308	2,000
85% CO_2 Reduction	2,393	2,588	2,338

The Zero Carbon Cost Build Plan scored lowest in one Market Scenario and second in the other two. But, the LNPV cost differences between those two Build Plans were relatively small, less than 2%, and the LNPV cost differences between the High Fossil Fuel Prices Build Plan and the Reference Build Plan is never more than 3.7%. The following table shows the percentage difference in NPV from the Reference Build Plan.

Table 2. Percentage Difference in NPV from Reference Build Plan

Core Build Plans Percentage Difference in NPV from Reference Build Plan			
Build Plans	**Reference Market Scenario**	**High Fossil Fuel Prices Market Scenario**	**Zero Carbon Cost Market Scenario**
Reference	0.00%	0.00%	0.00%
High Fossil Fuel Prices	3.70%	1.0%	1.60%
Zero Carbon Cost	0.60%	0.40%	-1.90%
70% CO_2 Reduction	10.00%	6.00%	10.60%
85% CO_2 Reduction	27.00%	18.80%	29.30%

The 85% CO_2 Reduction Build Plan has the highest LNPV cost across all three Core Market Scenarios by a wide margin, with an annual LNPV cost between \$411 million and \$529 million more annually than the Reference Build Plan under each Market Scenario. The difference between the 85% CO_2 Reduction Build Plan and the Reference Build Plan for each Market Scenario was an increase of between 18.8% and 29.3%.

Regarding carbon emissions, the 85% CO_2 Reduction Build Plan achieves the greatest CO_2 emissions reduction of the Core Build Plans producing an 86.8% to 86.9% reduction in CO_2 emissions from 2005 levels, but at higher LNPV cost. The 70% CO_2 Reduction Build Plan achieves the second highest reduction in CO_2 emissions levels with reductions from 2005 levels of between 71.2% and 71.3%, but also at higher LNPV costs. The following table summarizes the results of the carbon emissions reductions.

Table 3. 2050 CO_2 Reductions for the Core Build Plans Compared to 2005 Levels

Core Build Plans 2050 CO_2 Reductions Compared to 2005 Levels			
Build Plans	**Reference Market Scenario**	**High Fossil Fuel Prices Market Scenario**	**Zero Carbon Cost Market Scenario**
Reference	59.1%	63.3%	55.2%
High Fossil Fuel Prices	59.2%	63.3%	56.4%
Zero Carbon Cost	56.9%	63.2%	56.3%
70% CO_2 Reduction	71.3%	71.3%	71.2%
85% CO_2 Reduction	86.8%	86.9%	86.8%

Among the Reference Build Plan, the Zero Carbon Cost Build Plan, and the High Fossil Fuel Prices Build Plan, CO_2 emissions reductions vary between 55.2% and 63.3% from 2005 levels, with the Zero Carbon Cost Build Plan having the lowest reduction in two cases, and the second lowest in the other.

Q. HOW DID THE CORE BUILD PLANS PERFORM UNDER EACH METRIC?

A. The following table shows the rankings of the Core Build Plans across all eight metrics:

Table 4. Rankings of the Core Build Plans Against all Eight Metrics

Core Build Plans Rating Against All Metrics, Reference Case Where Applicable									
Core Build Plans	30-Year LNPV	2050 CO_2	Cum. CO_2	2050 Clean Energy	Fuel Cost	Gen. Diversity	Reliability	Mini-Max Regret	Cost Range
Reference	1	4	4	4	4	2	1	2	4
High Fossil Fuel Prices	3	3	3	3	3	5	1	3	3
Zero Carbon Cost	2	5	5	5	5	1	4	1	5
70% CO_2 Reduction	4	2	2	2	2	3	5	4	2
85% CO_2 Reduction	5	1	1	1	1	4	3	5	1

The Reference Build Plan scores quite well in metrics related to cost to customers, specifically 30-Year LNPV of generation costs and Mini-Max Regrets, reflecting the fact that it is optimized to produce lowest cost for customers under the Reference Market Scenario. The Zero Carbon Cost Build Plan also scores well in cost related categories.

Although the 85% CO_2 Reduction Build Plan has the best ratings related to CO_2 emissions, fuel costs, clean energy, and cost range, it is also the most expensive Build Plan with an annual LNPV cost to customers that is between $411 million and $529 million more than the Reference Build Plan under each Core Market Scenario. The 70% CO_2 Reduction Build Plan also scores well on CO_2 emissions, fuel costs, clean energy, and cost range, but is the second most expensive Build Plan with a levelized annual cost to customers that is between $131 million and $191 million more than the Reference Build Plan under each Core Market Scenario.

Q. WHAT PERCENTAGE OF RENEWABLE RESOURCES ARE SELECTED IN THE CORE BUILD PLANS?

A. Over the planning horizon, the Core Build Plans add non-emitting resources totaling between 80% and 87% of nameplate MWs of generation additions. The 85% CO_2 Reduction Build Plan adds the most non-emitting resources, 11,004 MW or 87%, and the Zero Carbon Cost Plan adds the least, 5,775 MW or 80%. The Reference Build Plan adds 6,625 MW of non-emitting resources or a little more than 80% of the total MW added under that Build Plan.

All Core Build Plans envision DESC adding substantial quantities of Solar on a roughly annual basis beginning in 2026 and supplemented by Battery beginning in 2028. On a nameplate MW basis, Solar and Battery combined are the principal resources added under all Core Build Plans.

Only the Carbon Constrained Build Plans envision adding offshore wind ("OSW"), which they add in the amounts of 800 MW or 1,100 MW and do so in 100 MW increments beginning in 2040. The 85% CO_2 Reduction Build Plan is the only Build Plan that envisions adding small modular reactor ("SMR") resources, which it adds in the amount of 804 MW in three stages beginning in 2040.

Q. DO THE TOTAL MEGAWATTS ADDED UNDER EACH CORE BUILD PLAN VARY?

A. Yes. For comparability purposes, DESC has based each of the Core Build Plans on the same load growth assumptions. This allows the levelized costs and CO_2

emissions of each Core Build Plan to be compared directly to the others. However, the total number of MW added under each Build Plan varies by a wide margin principally because of the intermittent nature of Solar and to a lesser degree, the cost of fuel avoided. Due to intermittency and their low Effective Load Carrying Capability ("ELCC"), adding Solar capacity provides only a small amount of the capacity needed to meet peak winter demand. For this reason, there is a strong correlation between the percentage of Solar added under a Build Plan, the fuel and CO_2 costs assumed in the Market Scenario, and the total amount of MW needed to meet customer demands.

Of the five Core Build Plans, the 85% CO_2 Reduction Build Plan adds the greatest amount of generating resources (12,591 MW) as well as the greatest amount of non-emitting resources (11,004 MW). The Zero Carbon Cost Build Plan adds the least amount of generating resources (7,222 MW) and the least amount of renewable resources (4,275 MW). The other Core Build Plans add between 8,333 MW (the Reference Plan) and 9,987 MW (the 70% CO_2 Reduction Build Plan) of total generating resources.

Q. WHAT ROLE DOES FOSSIL FUEL PLAY IN EACH BUILD PLAN?

A. Although most of the resources added in all Build Plans are non-emitting resources, the modeling shows that natural gas generation is also needed to support reliability and supply low-cost energy. Specifically, while each of the Core Build Plans adds at least 79.5% of non-emitting resources, each also adds at least 1,447

MW of natural gas fired generation to support system reliability. Load growth and other factors are the primary drivers of gas-fired generation additions. Comparing the Core Build Plans shows that PLEXOS makes very similar selections of natural gas-fired generators where Market Scenarios used similar load forecasts. The main differences were in the amount of Solar and Battery chosen. Where forecasts varied in high and low load scenarios, PLEXOS made selections of natural gas generation that were proportional to load growth.

Retiring the Wateree and Williams coal units creates a deficit in the reserve margin, and under each Core Build Plan, an initial increment of gas-fired generation is needed in response to maintain reliability. PLEXOS modeling shows that the most cost-effective resource mix to restore reserves to the planning reserve margin ("PRM") is a combination of natural gas-fired generation with some energy storage.

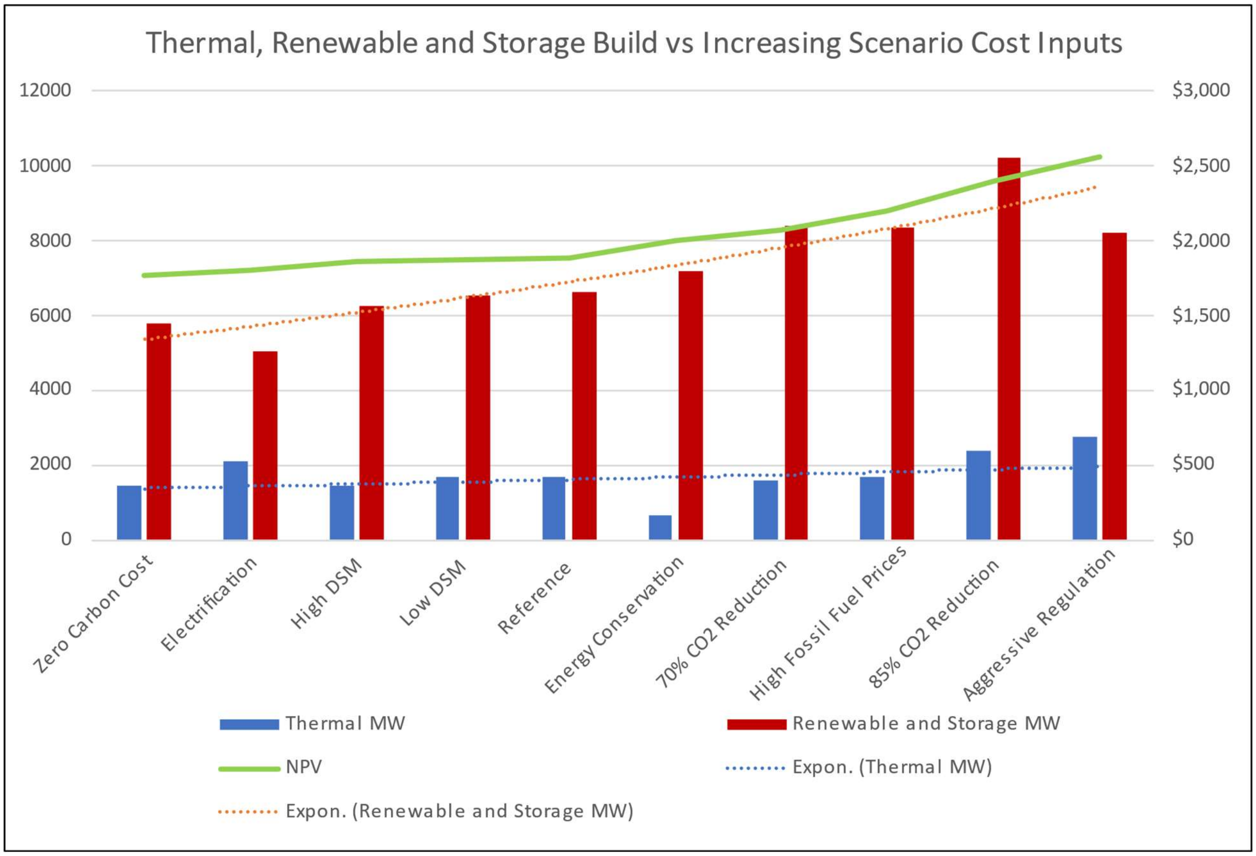
Even the Carbon Constrained Build Plans that result in a high-level of clean energy resource additions, and are the most expensive plans by far, both showed that significant gas-fired generation would be needed in the near term and going forward to support the combined retirement of the Wateree and Williams coal units. In addition, the Energy Conservation Build Plan, which was proposed by stakeholder groups, and which contained extremely optimistic assumptions about the potential ability of DSM programs and other efficiency measures to eliminate future demand growth, also determined that gas fired generation would be required in the near term to support the retirement of both Wateree and Williams.

Q. WHAT IS THE FORECAST OF RENEWABLE GENERATION UNDER THE CORE ANALYSIS?

A. All Core Build Plans add a significant amount of renewable generation. Using the Reference Market Scenario as an example, at the end of the forecast period each of the Core Build Plans includes between 59% and 68% renewable generation, as measured in MWs of nameplate capacity. As expected, the Carbon Constrained Build Plans result in the most renewables under each Market Scenario and the Zero Carbon Cost Build Plan the least. The Reference Build Plan ranks fourth under each Market Scenario. The energy generated from renewable resources is another metric. Over the planning horizon each of the Core Build Plans generates between 21% and 30% of the needed energy from renewable sources.

Comparing the LNPV of each Build Plan with the amount of renewable resources, there is a high correlation between the increased cost of electricity and the addition of renewable energy resources as shown in Figure 1. This is expected because PLEXOS selects resources based on which resources minimize cost under the given Market Scenario. This indicates that the overall cost of energy, as determined by fuel costs and CO_2 costs, is a principal driver of the model choosing renewable energy resources.

Figure 1: Thermal, Renewable and Storage Build vs. Increasing Scenario Cost Inputs



Q. WHY DO MOST BUILD PLANS ASSUME 2028 AND 2030 RETIREMENT DATES FOR THE WATEREE AND WILLIAMS COAL PLANTS, RESPECTIVELY?

A. As Mr. Walker testifies, DESC performed a comprehensive 2022 Coal Plants Retirement Study (the "Retirement Study") to inform development of its 2022 IRP Update and its 2023 IRP as required by Order Nos. 2020-832, 2021-418, and 2022-305. The Retirement Study was submitted to the Commission in Docket No. 2021-192-E in May 2022. The Retirement Study indicated that December 31, 2028 was a feasible and economic retirement date for Wateree and December 31, 2030 was the earliest feasible and economic retirement date for Williams. For modeling purposes, those dates have been used in all Build Plans except for two sensitivities that were modeled to inform the choice of 2030 as the retirement date of Williams.

Q. HOW DOES THE PLEXOS MODELING INFORM DESC'S DECISION ON WHEN AND HOW TO REPLACE WATEREE AND WILLIAMS?

A. In the Supplemental Cases, DESC evaluated two possible approaches for replacing Wateree, assuming it can be retired by December 31, 2028. While there were differences among individual Build Plans, in summary the two primary approaches identified by PLEXOS utilizing the candidate resources available to it in the Core Build Plans are: (1) 400 MW of battery storage to be added in 2029; or (2) a 262 MW Large Frame Combustion Turbine ("CT") along with 100 MW of battery storage added in 2029.

To evaluate these replacement options, DESC instructed PLEXOS to optimize two Build Plans under the Reference Market Scenario, each adopting one of the alternative Wateree replacement plans as a fixed assumption. The Wateree Battery Build Plan assumes the addition of 400 MW of four-hour duration, standalone battery energy storage in 2029. This Wateree Battery Build Plan assumes zero electric transmission interconnection costs by siting the resources at the existing Wateree site and optimizes subsequent generation additions assuming the addition of that resource. The Wateree CT Build Plan assumes the addition of a 262 MW Large Frame CT at the Urquhart Station site and a 100 MW energy storage facility at the Wateree site in 2029 and optimizes subsequent generation additions assuming the addition of that resource. The Wateree CT Build Plan includes electric transmission interconnection cost assumptions provided by DESC's Electric Transmission Planning group from the 2022 Transmission Impact Analysis ("TIA") request.

The modeling shows that the Wateree Battery Build Plan is the lower cost of the two options, but the cost difference in terms of LNPV is relatively small, $23 million or 1.25%. The two Build Plans produce slightly different cumulative CO_2 emissions over the planning horizon. The Wateree Battery Build Plan has modestly higher cumulative CO_2 emissions than the Wateree CT Build Plan, primarily due to timing differences related to Battery and CT additions and the available system resources from which standalone battery energy storage would charge. At the end of the planning horizon the Wateree Battery Build Plan has higher 2050 CO_2 emissions, but the difference is still small, only 0.27%. It should be noted that this modeling used the candidate resource cost estimates used in developing all of the IRP modeling. The costs of actual replacement resources from a competitive solicitation, as proposed in the testimony of Mr. Walker, should be utilized to determine the ultimate optimized mix of resources to replace Wateree.

For Williams, PLEXOS identified that the optimum replacement is a large and highly efficient natural gas-fired 1,325 MW Combined Cycle ("CC") resource shared with Santee Cooper (the "Shared Resource"). As a rule of thumb, a CC unit is approximately 35% more fuel efficient than a CT unit, resulting in lower fuel costs and emissions. In modeling the Shared Resource, DESC assumed for modeling purposes that it would have a one-half ownership stake in the facility and accordingly, receive one-half of its output. This Shared Resource was identified by PLEXOS as the optimum replacement resource for Williams in ten of the fourteen Build Plans that modeled Williams replacement resources in 2030. The Williams 2047 Retirement Build Plan and the High Fuel Williams 2047 Build Plan did not retire Williams until 2047 and so they did not select replacement resources in 2030. The two Build Plans that did not select the Shared Resource are the Carbon Constrained Build Plans. Each of them identified a 1,325 MW CC unit with DESC having full ownership of the facility and its output as the optimum replacement for Williams. In all other Build Plans, the Shared Resource was the optimal replacement resource for Williams in 2031.

As Ms. Best and Mr. Walker testify, building a Shared Resource could create economies of scale for all participating utilities, reducing costs to their customers including the electric cooperatives in the state, enhancing efficiencies in natural gas pipeline expansions, and reducing the environmental footprint of the generation facilities and natural gas pipeline projects needed to replace coal generation on both systems. It could help anchor an expansion of natural gas supplies for uses other than power generation in areas of the state where economic development is limited by lack of such supplies and create a more certain timetable for achieving carbon reductions on both systems.

Q. HOW DOES THE 2023 IRP INFORM DECISIONS ON THE RETIREMENT DATE FOR WILLIAMS?

A. Under most Build Plans, the retirement date for Williams is assumed to be December 31, 2030. As a comparison, DESC created two additional Build Plans through PLEXOS by setting the retirement date for Williams in 2047, at the end of its useful life, under the Reference Market Scenario (the "Williams 2047 Build Plan") and the High Fossil Fuel Prices Market Scenario (the "High Fuel Williams 2047 Build Plan").

Comparing the Williams 2047 Build Plan to the Reference Build Plan shows that retiring Williams by 2030 reduces the annual LNPV costs to customers by approximately $25 million, or 1.32%, and results in a small reduction (0.14%), in the compound rate of growth in retail rates. Under the Reference Market Scenario, retiring Williams early also reduces cumulative CO_2 emissions over the planning horizon by 3.37%. However, since Williams is assumed to retire before the end of the planning horizon in any case, the reduction in 2050 CO_2 emissions from retiring Williams early is only 0.44%.

Comparing the early or later retirement dates for Williams under the High Fossil Fuel Prices Market Scenario shows that retiring Williams by 2030 generates an annual reduction in the LNPV of charges to customers of $36 million, or 1.66%, and a 0.21% reduction in compound annual growth rate compared to the High Fuel Williams 2047 Build Plan. Retiring Williams early under the High Fossil Fuel Prices Market Scenario reduced cumulative CO_2 emissions by 10,054 ktons or 5.3% more reduction than the High Fuel Williams 2047 Build Plan over the planning horizon, but CO_2 emissions are expected to be practically the same in 2050 because Williams retires in 2047 under both cases.

This analysis supports DESC's decision to continue to set December 31, 2030, as the assumed retirement date for Williams for planning purposes. That will also be the date by which resources to replace Williams' capacity would need to be completed and available for service. It is worth noting that there are significant uncertainties surrounding the timing for a Williams replacement due to its role in supporting transmission system reliability, which in turn create significant uncertainties concerning the achievability of the retirement date. This issue is discussed in more detail in the testimony of Mr. Walker.

Q. WHAT ADDITIONAL INSIGHTS WERE GAINED FROM THE SENSITIVITY ANALYSIS?

A. In addition to the Core Analysis, DESC modeled five additional Market Scenarios as Sensitivity Cases to fulfill requirements of the IRP Statute and Commission mandates. The Sensitivity Cases assume varying levels of CO_2 costs, environmental regulations, economic growth and load growth, and DSM effectiveness and confirm the representative nature of the Core Build Plans and the value of the planning insights they provide. Concerning DSM sensitivities, DESC modeled the maximum achievable and low achievable DSM levels in the High and Low DSM Sensitivity Cases and used the Medium DSM level as the assumption in the Reference Market Scenario and most other Market Scenario. The difference in the resulting build plans were not material to planning decisions to be made in the near term. The complete evaluation of the Sensitivity Cases is contained on pages 79-84 of the 2023 IRP and is incorporated herein by reference.

Q. IS DESC'S PREFERRED PLAN SUPPORTED BY THE MODELING?

A. Yes. The modeling supports the Reference Build Plan as the Preferred Plan to guide DESC's planning decisions at this time. The Reference Build Plan is the lowest cost option with the lowest regrets score of any plan under the Reference Market Scenario which represents DESC's assessment of the likely conditions to be encountered during the planning period. The only Build Plan that is comparable in terms of cost considerations under any of the three Core Market Scenarios is the Zero Carbon Cost Build Plan, which only out-performs the Reference Build Plan as to cost or regrets under the assumption that carbon emissions remain zero cost for the duration of the planning period. This is not an assumption on which DESC believes it should base its generation planning at this time because it fails to address the risk of future regulations and costs for CO_2 emissions which is not a risk that DESC should ignore. The Carbon Constrained Build Plans outperform the

Reference Build Plan on most measures of CO_2 emissions reductions and clean energy. But their costs are significantly higher than the Reference Build Plan.

Q. WHAT OTHER PLANNING DECISIONS DOES THE MODELING SUPPORT?

A. The modeling also supports the need for at least 662 MW additional capacity to be on line before Williams is retired which supports the decision to proceed with upgrades to comply with the U.S. Environmental Protection Agency ("EPA") Steam Electric Effluent Limitation Guidelines ("ELG") requirements for Williams to continue to run until at least December 31, 2030, and the decision to replace Williams with the Shared Resource. The principal difference between the Reference Build Plan and the Carbon Constrained Build Plans is that the Reference Build Plan replaces Wateree and Williams with 400 MW of Battery followed in 2031 by the 626 MW Shared Resource facility, while the Carbon Constrained Build Plans replace Wateree with 100 MW of Battery, a 262 MW Frame CT followed in 2031 by a 1,325 MW CC unit with no assumption as to shared ownership. Adopting the Reference Build Plan as the Preferred Plan under this 2023 IRP does not eliminate either alternative and makes no prejudgment with respect to the ultimate mix of replacement resources to retire Wateree and Williams.

MODELING INPUTS AND ASSUMPTIONS

Q. WHAT ARE THE DIFFERING FUEL PRICE FORECASTS THAT WERE USED IN THE MARKET SCENARIOS?

A. The Market Scenarios used three difference fuel price forecasts: low, medium, and high. The medium or base natural gas price forecast for the first three years of the planning horizon reflects the reported prices of publicly traded NYMEX Henry Hub contracts. For years 2026-2050, the forecast incorporates the IHS North American Power Market Outlook for natural gas at Henry Hub. IHS is a global forecasting and technology firm that is owned by S&P Global.

To create the high and low natural gas price forecasts, DESC adjusted its base natural gas price forecast by the percentage difference each year between the reference natural gas price forecast and the high or low natural gas price forecast provided by the U.S. Energy Information Administration ("EIA") in its Annual Energy Outlook ("AEO").

The natural gas prices used in the PLEXOS model include both Henry Hub commodity prices and costs to deliver the natural gas to each generating unit. Delivered costs include forecasts for delivery costs which include transportation costs on upstream pipelines, basis differential, allowance for fuel used by pipelines for compression and other purposes (commonly known as shrinkage) and all other natural gas transportation costs. Each generating unit has a different delivered cost of gas based on the upstream pipelines used to deliver gas to that generating unit, the tariffs or contracts under which that natural gas is delivered, and the gas producing region supplying the commodity. A single supply point may serve multiple generating units. The forecast of the future cost to deliver gas to each existing unit is based on the actual cost of delivered gas to the majority of generation assets at each gas supply point. PLEXOS accounts for these costs on a unit-by-unit basis and the actual delivered price of natural gas varies from year to year and under each Build Plan as units are dispatched by the PLEXOS model. For new natural gas units, DESC uses estimated prices for new gas transportation that have been provided by upstream natural gas pipelines for units on DESC's system.

DESC's forecasted coal prices are based on the Company's direct knowledge of Appalachian coal contract prices for the years 2023-2025 based on its coal purchasing activities and IHS forecasts for years 2026-2050. High and low coal price forecasts were also based on the difference between the reference and the high or low-price forecast provided by EIA in its AEO data.

Q. WHAT ARE THE DIFFERING CO_2 PRICES THAT WERE USED IN THE MARKET SCENARIOS?

A. DESC developed three CO_2 pricing views for this IRP to reflect a wide range of possible emissions pricing pressures over the coming decades. The medium CO_2 price, used in five of the Market Scenarios, assumes that a \$9.62/Mton CO_2 price is imposed starting in 2030, which then escalates to more than \$45/Mton by 2050. This is the IHS "US Power Sector" forecast. Again, IHS is a global forecasting company and is widely recognized in the industry. Only one market scenario, Aggressive Regulation, use the High CO_2 prices.

For the high view of CO_2 prices, DESC assumed that CO_2 prices would start two years earlier in 2028 and would be 50% higher ($14.43/Mton) than the IHS forecast. The price escalates to $37/Mton by 2040 and $80/Mton by 2050.

Two Market Scenarios are based on a zero CO_2 price assumption that reflects a continuation of current state and federal policies that do not put any explicit price on CO_2 emissions. This assumption creates a CO_2 sensitivity against which all other Build Plans can be evaluated and provides a consistent basis that is unaffected by CO_2 cost variables to assess the comparative impact of fuel and load growth variables across these five plans. The two Build Plans that use the zero CO_2 cost are the Zero Carbon Cost, and Electrification Build Plans.

Q. WHAT ARE THE DIFFERING LOAD GROWTH FORECASTS THAT WERE USED IN THE MARKET SCENARIOS?

A. The reference load growth forecast is discussed in the testimony of Mr. Perricelli. Low and High load growth assumptions were created by adjusting the load growth up or down by 0.5% to achieve a wide but plausible range of future load growth.

Q. WHAT ARE THE DIFFERING DSM SCENARIOS THAT WERE USED IN THE MARKET SCENARIOS?

A. DESC modeled three assumptions concerning the effectiveness of DSM programs to limit load growth. The High DSM case assumes that DESC is able to achieve a reduction in annual forecasted load growth (excluding opt-out customers) of 0.74% of energy sales, which is the maximum achievable reduction determined in the 2023 DSM Potential Study consistent with cost-effectiveness, market data concerning DESC's service territory, and other benchmarking data. The Medium DSM case assumes that DESC can achieve a 0.51% energy sales reduction due to DSM programs, which is the level the 2023 DSM Potential Study found to be an achievable reduction. The Low DSM case assumes that DESC is only able to achieve 90% of the energy reductions assumed under the Medium DSM case or 46%. All of DESC's energy and demand values include marginal line losses for DSM. Each of these cases is described in more detail in the 2023 DSM Potential Study, and in the testimony provided by Ms. Shelton and Mr. Durkee.

Q. WHAT ASSUMPTIONS COMMON TO ALL BUILD PLANS WERE CONSIDERED IN THE MODELING?

A. Each of the fourteen Build Plans assume that DESC can retire Wateree in 2028. All but two assume that DESC retires Williams in 2030. The two exceptions are the Williams 2047 Build Plan and High Fuel Williams 2047 Build Plan, which provide a basis for comparing the cost and CO_2 emissions impacts of delaying the Williams retirement until the end of its useful life in 2047 instead of retiring it early.

In constructing these Build Plans, DESC informed the PLEXOS model to limit the dual-fuel (coal and natural gas firing capable) Cope Station ("Cope") to use only natural gas as a fuel beginning in 2031. To convert Cope to a natural gas only operation will require additional natural gas firm transportation; it is reasonable to assume that the Company may acquire such additional transportation to fuel Cope at the same time that it acquires incremental transportation for other new gas fired facilities like the Shared Resource.

Q. WHAT WERE THE RESERVE MARGIN REQUIREMENTS FOR PLEXOS TO CREATE EACH BUILD PLAN?

A. DESC informed the PLEXOS model to maintain a single integrated minimum 20.1% winter reserve margin based on the 2023 Planning Reserve Margin Study prepared by Astrapé Consulting. In all cases, meeting the winter reserve margin drove the addition of generation resources by PLEXOS.

Q. WHAT RECENTLY ADDED OR UPGRADED GENERATION RESOURCES DID PLEXOS CONSIDER?

A. The PLEXOS model includes as existing generation resources all binding solar Power Purchase Agreements ("PPAs") whether already in service or at the time of the modeling was under binding contract to come on line in the coming years. They total 1,108 MW of nameplate capacity and include a soon to be added paired solar and energy storage PPA with 73.6 MW of nameplate capacity and an 18 MW four-hour duration battery. The PLEXOS model also recognized as existing resources the planned replacement Bushy Park and Parr CT resources that are currently under construction. The existing Urquhart CT units and gas steam unit were modeled as-is, as the Urquhart Replacements All Sources RFP was pending during the development of the 2023 IRP. The Company anticipates being able to include the results of the RFP in the 2024 IRP Update. The existing CC units' capacity reflects the AGP upgrades at Jasper Station and Columbia Energy Center that enhance the capabilities and improve the fuel efficiency of those units.

Q. WHAT GENERATING RESOURCES WERE AVAILABLE TO PLEXOS IN CREATING THE BUILD PLANS?

A. In consultation with Stakeholders, DESC decided to model twelve generating resources plus two demand response ("DR") resources for PLEXOS to select to build when optimizing generation plans to meet future demand. These resources included two configurations of standalone battery capacity, two configurations of standalone solar capacity, three configurations of CTs, three configurations of CC units, OSW, and SMRs. Solar resources are modeled as PPA resources in addition to utility-owned resources. The cost of Solar resources reflects production tax credits from the recently enacted Inflation Reduction Act ("IRA") for the duration of the programs under it and any safe harbor extensions for uncompleted projects. Battery resources in the modeling reflect investment tax credit benefits provided under the IRA on a similar basis and are modeled at an assumed capacity availability of either 85% or 50% which means that the Battery is assumed to be able to provide either 85% or 50% of its capacity to help meet the reserve margin requirement. The two DR programs are modeled as resources using cost data provided by the 2023 DSM Potential Study.

Q. HOW WERE THE COSTS ASSOCIATED WITH EACH OF THE TECHNOLOGIES CALCULATED?

A. The capital costs, escalation in capital cost, operating and maintenance ("O&M") costs, and other attributes of each of the resources available for selection by PLEXOS are listed in Table 5, below. These costs have been determined and incorporated in the modeling after consultation with Stakeholders. For candidate resources, the capital costs of the resources modeled in each plan have been escalated from 2023 to the year that the generator is ultimately installed.

All prices for renewables have been updated with nominal prices calculated from the National Renewable Energy Laboratory ("NREL") 2022 Annual Technology Baseline ("ATB") with the addition of production tax credits ("PTC") or investment tax credits ("ITC") as described below.

Through the stakeholder process, DESC agreed to use NREL ATB cost data for Solar and Battery. In working with that data, DESC determined that NREL embedded aggressive forecasts of future cost reductions for solar technology in it. These forecasted cost reductions are inconsistent with the recent trend of price increases for Solar and Battery, and the planning data used by other Dominion Energy companies. DESC is concerned that these aggressive forecasts of future price reductions may have increased the amount of Solar selected by PLEXOS to a level that will not be realized but these are long-term issues and are likely to have limited effects on the major resource procurement decisions that will be made on the basis of this 2023 IRP. These prices will be adjusted as bid data and other market data become available and major resource procurement decisions will be made on bids for actual resources and based on actual costs.

Table 5. Generation Supply Technology Costs, Escalation and Capacity Units and Supply Technology Characteristics

Available Resources	Capital Cost ($2022/kW)	Escalation Rate	Capacity (MW)	Source Of Data
New 1x1 Combined Cycle	1,452	1.89%	650	Dominion Energy Services - Project Construction Financial Management & Controls
New 2x1 Combined Cycle	1,163	1.89%	1,325	Dominion Energy Services - Project Construction Financial Management & Controls
New 2x1 Combined Cycle 50 Shared	1,163	1.89%	662	Dominion Energy Services - Project Construction Financial Management & Controls
New 3x1 Combined Cycle	941	1.89%	1,950	Dominion Energy Services - Project Construction Financial Management & Controls
New CT Aero 2x	1,898	1.89%	114	Dominion Energy Services - Project Construction Financial Management & Controls
New CT Frame 1x	1,402	1.89%	262	Dominion Energy Services - Project Construction Financial Management & Controls
New CT Frame 2x	1,154	1.89%	523	Dominion Energy Services - Project Construction Financial Management & Controls
New Small Modular Reactor	12,354	1.89%	274	Dominion Energy Services - Project Construction Financial Management & Controls
New Solar (two forms, utility-owned and PPA)	1,240	2.5%	75	NREL 2022 ATB
New Battery (4 hour duration)	1,459	2.5%	100	NREL 2022 ATB
New Off Shore Wind	4,323	2.5%	100	NREL 2022 ATB

Q. WHAT ARE THE RESOURCES LISTED AS “2X” OR “2X1”?

A. Economies of scale benefit adding natural gas resources in multiples at the same time. For simple cycle units, this is denoted as “CT 2x”. The combined cycle gas resources modeled are configured with one or more CT units as well as one steam turbine. The CC 2x1 notation means a combined cycle unit composed of two combustion turbines with one steam turbine. Similarly, the CC 1x1 notation means a combined cycle unit composed of one combustion turbine and one steam turbine. The MW value listed is for the sum of the total units.

Q: PLEASE EXPLAIN HOW PLEXOS ACCOUNTS FOR INTEGRATION COSTS OF INTERMITTENT ASSETS AND WHY THE INTEGRATION COSTS ARE TREATED DIFFERENTLY BETWEEN PPAS AND COMPANY-OWNED ASSETS.

A. Integration costs are captured for both utility owned and PPA renewable resources through the increase in spinning reserves and regulation reserves. PLEXOS models an additional 35% spinning reserve and an additional 10% regulation reserve for renewable resources. The total costs that DESC will pay to the third-party developer are the NREL costs plus the variable integration charge. The PPA resources will be charged $1.80/MWh to cover the additional integration costs which are not included in the NREL costs that are being modeled and therefore the cost of PPA resources are increased by $1.80/MWh. The $1.80/MWh is the value ordered by the Commission in Order No. 2022-329. The company does not pay itself the $1.80/MWh charge for company owned resources.

Q. DID THE IRP INCORPORATE ANY UPDATES OR SAVINGS FROM THE INFLATION REDUCTION ACT?

A. Yes, under the IRA, standalone battery energy storage resources are now eligible for tax incentives. As a result, this IRP is the first full IRP to model Battery as a standalone resource eligible for tax credits.

Additionally, DESC incorporated a base level of IRA-based tax incentives into its modeling. PLEXOS assumes that all Solar resources receive a PTC starting at $27.50 per MWh and escalating annually and that Battery resources receive a 30% ITC on 85% of the total project cost. While the U.S. Treasury Department is still developing implementation guidance for the IRA, under previous tax policy for ITCs, not all project costs qualify for the credit; DESC believes that 85% is a reasonable estimate of the project components that would qualify for modeling purposes. The modeling presented here assumes that the ITC and PTC apply to projects completed during the life of the program and for two years after the program closes to capture projects grandfathered into eligibility that were begun before the sunset date.

Q. WERE ANY BUILD CONSTRAINTS PLACED ON ANY OF THE RESOURCES IN PLEXOS?

A. Yes, every resource in PLEXOS is subject to a build constraint. For the model to run, there must be a maximum number of units of that resource it can choose over the planning horizon. The size of a unit of most resources, CC 2x1, CC 1x1, CT, or CT x2 for example, is such that PLEXOS would not ordinarily select an unreasonable quantity of a single unit in a single year. And so there is no practical reason to impose an annual build constraint on such resources. That is not the case with solar resources. To account for this, DESC incorporated a 300 MW annual constraint on the addition of solar resources. There was no annual constraint on battery resources.

Q. IS IMPOSING A BUILD CONSTRAINT ON SOLAR REASONABLE?

A. It is reasonable to impose a build constraint on solar. Build constraints on solar are a common feature in resource planning by other utilities and ensures that solar resources are modeled as being added to the system in reasonably sized increments over time, not all at once in a given future year. Incrementally adding resources further reflects the realities of the procurement and supply chain processes and results in more reasonable and actionable results. This constraint was based on historical build rates as a percentage of their overall system size by DESC, Dominion Energy Virginia ("DEV"), and Duke Energy Carolinas ("DEC") and Duke Energy Progress ("DEP") in their service territories in South Carolina, North Carolina, and Virginia. DESC also considered NREL data on US build rates. There were no annual constraints placed on battery resources.

Q. IN YOUR PROFESSIONAL OPINION, DID THE RESOURCE MODELING CONDUCTED FOR THE 2023 IRP COMPLY WITH ALL STATUTORY REQUIREMENTS AND COMMISSION ORDERS?

A. Yes.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.